GCA

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Technical and Management Advisers to the Petroleum Industry Internationally Since 1962

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Mr. Lincoln R. Guardado
Diretor de Exploração
Queiroz Galvão Exploração e Produção S.A.
Av. Presidente Antonio Carlos 51/5o andar
20029-010 Rio de Janeiro, RJ, Brasil

HYDROCARBON RESERVE AND RESOURCES STATEMENT
FOR CERTAIN PROPERTIES IN BRAZIL
AS OF DECEMBER 31, 2009

Dear Mr. Guardado:

This reserve and resource statement has been prepared by Gaffney, Cline & Associates (GCA) at the request of Queiroz Galvão Exploração e Produção S.A. (QGEP), operator of and 30% interest participant in the Exploration Block BM-S-12 offshore Brazil, operator and 100% interest participant in the Exploration Block BM-J-2 offshore Brazil and non operator with various interest participant in the Manati and North of Camarão fields of the BCAM-40 Block, and the BM-CAL-5, BM-CAL-12, BM-S-75, BM-S-76 and BM-S-77 Exploration Blocks offshore Brazil. Fields and prospects and participation of QGEP in these blocks are summarized in the following table.

Block	Basin	QGEP Interest	Field / Prospect	Resource Category	Fluid
BCAM-40	Camamu	45%	Manati	Reserves	Gas
BCAM-40	Camamu	45%	Camarão Norte	Contingent	Gas-Oil
BM-CAL-5	Camamu	22.50%	Copaíba	Contingent	Oil
BM-CAL-5	Camamu	27.50%	Jequitibá	Contingent	Gas
BM-CAL-12	Camamu	20%	CAM-1	Prospective	Oil
BM-J-2	Jequitinhonha	100%	JEQ-1	Prospective	Gas
BM-J-2	Jequitinhonha	100%	JEQ-2	Prospective	Gas
BM-S-12	Santos	30%	Santos 1	Contingent	Gas
BM-S-12	Santos	30%	Santos 1 UCR1	Prospective	Gas
BM-S-12	Santos	30%	Santos 1 UCR2	Prospective	Gas
BM-S-12	Santos	30%	Santos 1 UCR3	Prospective	Gas
BM-S-12	Santos	30%	Santos 1 UCR4	Prospective	Gas
BM-S-12	Santos	30%	Santos 2	Prospective	Oil
BM-S-12	Santos	30%	Santos 3	Prospective	Oil
BM-S-12	Santos	30%	Santos 4	Prospective	Gas
BM-S-75/76/77	Santos	20%	Santos 5	Prospective	Oil
BM-S-75/76/77	Santos	20%	Santos 6	Prospective	Oil
BM-S-75/76/77	Santos	20%	Santos 7	Prospective	Gas
BM-S-75/76/77	Santos	20%	Santos 8	Prospective	Oil
BM-S-75/76/77	Santos	20%	Santos 9	Prospective	Oil

GCA has conducted an independent audit examination as of December 31, 2009, of the hydrocarbon reserves and resources of these areas. On the basis of technical and other information made available to us concerning these property units, we hereby provide the statements given in the tables below.

Hydrocarbon Reserves Statement as of December 31, 2009
Manati Field, Brazil
Gross and Net to Queiroz Galvão Exploração e Produção's Interest

Category	Condensate				Natural Gas			
	Gross (100%) Field Volumes		Net to QGEP's Interest Volumes		Gross (100%) Field Volumes		Net to QGEP's Interest Volumes	
	(MMBbl)	(Mm^3)	(MMBbl)	(Mm^3)	(Bcf)	(Bcm)	(Bcf)	(Bcm)
1P	1.9	299	0.8	135	636	18.0	286	8.1
2P	2.6	410	1.1	185	873	24.7	392	11.1
3P	3.0	466	1.3	210	992	28.1	445	12.6

The existing gas sales contract with Petrobras is for a maximum delivery of 23 Bcm or a remaining total of 18 Bcm after subtracting the cumulative production at the "as of" date of December 31, 2009. This volume has been categorized as Proved.If the gas sales contract had been modified or had new sales contracts been in place, the estimated volume of Proved Reserve (1P) could have increased to a maximum of 21.3 Bcm for the 100% gross field (9.6 Bcm net to QGOG)..

Condensate volumes estimated to be recovered during field separation are reported in millions of stock tank barrels and thousands of cubic meters. Natural gas volumes represent expected gas sales and are reported in billions (10^9) of cubic feet and billions (10^9) of cubic meters (at standard conditions of 14.7 psia and 68º Fahrenheit). The volumes have been reduced for fuel usage in the fields. Article 47 of the Brazilian Petroleum Law states that "…royalties are to be paid on a monthly basis, in national currency …" and therefore royalties are treated as cash deductions rather than a reduction to volumes. Gas volumes are based on firm and existing gas contracts and on the reasonable expectation that such gas sales contracts will be renewed on similar terms in the future.

The Camamu/Almada Basin is located offshore from the state of Bahia, northeastern Brazil. The concession, covering approximately 935 km^2, was awarded to Petrobras in 1998. In 1999 Petrobras presented a farm in opportunity for participation in the concession. There are two fields in this area considered in this report in which QGEP has a participating interest of 45%, both in the BM-CAM-40 block, Manati and Camarão Norte (formerly BAS-131). Both are in shallow waters, approximately 20-50 meters deep and 10-20 km from shore.

Manati Field is a dry gas field that started production in 2007 from the Sergi Fm. There is a current sales contract for a rate of 6 million cubic meters per day and a total sales volume of 23 billion cubic meters. In order to produce the reserves volumes compression will be needed. In order to maintain the sales volume plateau rate for as long as possible for the larger volumes in the 2P and 3P categories, compression will be required in 2013. As the Proved reserves are limited by the current contract, less compression is required and not be needed until 2015.

The Camarão Norte Field in the BCAM-40 Block is in the process of being unitized in view of its extension onto the contiguous block BM-CAL-04 to the south, where El Paso is the operator and has 100% interest. The Camarão Norte field is prospective from the Sergi Formation holding a gas cap and a rather small oil zone. Oil has been discovered and tested in the Morro do Barro Formation. Several plans are being considered to develop the field once unitization is concluded. The plans for the Camarão Norte are to exploit only the Sergi gas in the 1C case and to develop both the oil and gas in Sergi in the 2C case. In the 3C case the Morro do Barro Fm. is included. The Sergi will be developed with horizontal drilling, one well in the 1C case and 3 wells in the 2C case. An additional 3 vertical wells for the Moro do Barro are included in the 3C case. Gas would be exported through the Manati facilities in any case.

Production history during 2009, coupled with the geological and simulation model of the field, constitutes the basics for the methodology applied in the Manati Field case, while volumetric calculations of the OGIP and the simulation work for the estimation of the gas recovery factors, were used in the assessment of the contingent resources for the Camarão Norte .The Camarão Norte assessment is based on an overall unitization factor of 45.17% as determined from volumetric estimates of the OGIP.

This audit examination was based on reserve and resource estimates and other information provided by QGEP to GCA through April 30, 2010, and included such tests, procedures and adjustments as were considered necessary. All questions that arose during the course of the audit process were resolved to our satisfaction.

The commerciality and economic tests for the December 31, 2009 Reserves volumes were based on gas sales price contractually stated. This value corresponds in 2010 to US$ 7.74/Mcf after converting Reais to US Dollars, grossing up of local taxes (21.25%) and reducing for Nitrogen content of 5.8%. Gas prices after 2010 were taken at a 2% per year inflation. The future scenario of condensate price was based on the GCA's future scenario of Brent crude oil price plus a premium of US$8.00/bbl as stated by sales contract.

Price scenario for Manati Field Reserves estimation

Year	GCA Brent Oil Scenario US$/Bbl	Condensate US$/Bbl	Gas US$/MMBtu
2010	80.94	88.94	7.74
2011	85.76	93.76	7.89
2012	88.02	96.02	8.05
2013	87.21	95.21	8.21
2014	86.59	94.59	8.38
2015	88.33	96.33	8.54
Thereafter	+2% / year	+2% / year	+2% / year

Cashflows are included in Appendix II.

Contingent Hydrocarbon Resources Statement as of December 31, 2009
Properties offshore Brazil
Gross and Net to Queiroz Galvão Exploração e Produção's Interest

Category	Field	Oil / Condensate				Natural Gas				QGEP
		Gross (100%) Field Volumes		Net to QGEP's Interest Volumes		Gross (100%) Field Volumes		Net to QGEP's Interest Volumes		Participation
		(MMBbl)	(Mm^3)	(MMBbl)	(Mm^3)	(Bcf)	(Bcm)	(Bcf)	(Bcm)	%
1C										
	Camarão Norte	---	---	---	---	57	1.6	15	0.4	45.0%
	Copaíba	18.2	2,897	4.1	652	12	0.3	3	0.1	22.5%
	Jequitibá	0.6	102	0.2	28	72	2.0	20	0.6	27.5%
	Santos #1	0.0	7	0.0	2	9	0.3	3	0.1	30.0%
2C										
	Camarão Norte	6.3	1,003	1.4	226	53	1.5	12	0.3	45.0%
	Copaíba	37.8	6,015	8.5	1,353	25	0.7	6	0.2	22.5%
	Jequitibá	1.5	235	0.4	65	166	4.7	46	1.3	27.5%
	Santos #1	0.1	19	0.0	6	23	0.7	7	0.2	30.0%
3C										
	Camarão Norte	9.3	1,482	2.1	333	61	1.7	14	0.4	45.0%
	Copaíba	71.2	11,317	16.0	2,546	48	1.4	11	0.3	22.5%
	Jequitibá	3.0	472	0.8	130	334	9.4	92	2.6	27.5%
	Santos #1	0.3	41	0.1	12	51	1.4	15	0.4	30.0%

Prospective Hydrocarbon Resources Statement as of December 31, 2009
Properties offshore Brazil
Gross and Net to Queiroz Galvão Exploração e Produção's Interest

Estimate	Prospect	Oil / Condensate				Natural Gas				Geologic Chance of Success	QGEP Participation
		Gross (100%) Field Volumes		Net to QGEP's Interest Volumes		Gross (100%) Field Volumes		Net to QGEP's Interest Volumes			
		(MMBbl)	(Mm^3)	(MMBbl)	(Mm^3)	(Bcf)	(Bcm)	(Bcf)	(Bcm)	%	%
Low (P90 probabilistic estimate)											
	CAM 01	130.5	20,751	26.1	4,150	73	2.1	15	0.4	31%	20%
	JEQ #1	3.1	490	3.1	490	433	12.3	433	12.3	29%	100%
	JEQ #2	2.4	387	2.4	387	273	7.7	273	7.7	24%	100%
	Santos #1 UCR1	0.2	29	0.1	9	35	1.0	11	0.3	30%	30%
	Santos #1 UCR2	0.1	8	0.0	3	10	0.3	3	0.1	30%	30%
	Santos #1 UCR3	0.1	20	0.0	6	25	0.7	8	0.2	30%	30%
	Santos #1 UCR4	0.0	7	0.0	2	9	0.3	3	0.1	30%	30%
	Santos #2	80.4	12,781	24.1	3,834	83	2.3	25	0.7	39%	30%
	Santos #3	36.4	5,789	10.9	1,737	37	1.1	11	0.3	19%	30%
	Santos #4	18.7	2,979	5.6	894	1578	44.7	473	13.4	40%	30%
	Santos #5	64.0	10,181	12.8	2,036	54	1.5	11	0.3	18%	20%
	Santos #6	28.2	4,477	5.6	895	24	0.7	5	0.1	18%	20%
	Santos #7	3.8	604	0.8	121	427	12.1	85	2.4	11%	20%
	Santos #8	38.6	6,134	7.7	1,227	22	0.6	4	0.1	23%	20%
	Santos #9	17.2	2,738	3.4	548	13	0.4	3	0.1	20%	20%

Prospective Hydrocarbon Resources Statement as of December 31, 2009
Properties offshore Brazil
Gross and Net to Queiroz Galvão Exploração e Produção's Interest

Estimate	Prospect	Oil / Condensate				Natural Gas				Geologic Chance of Success	QGEP Participation
		Gross (100%) Field Volumes		Net to QGEP's Interest Volumes		Gross (100%) Field Volumes		Net to QGEP's Interest Volumes			
		(MMBbl)	(Mm^3)	(MMBbl)	(Mm^3)	(Bcf)	(Bcm)	(Bcf)	(Bcm)	%	%
Best (P50 probabilistic estimate)											
	CAM 01	303.8	48,294	60.8	9,659	171	4.8	34	1.0	31%	20%
	JEQ #1	7.6	1,208	7.6	1,208	1,067	30.2	1,067	30.2	29%	100%
	JEQ #2	6.1	965	6.1	965	681	19.3	681	19.3	24%	100%
	Santos #1 UCR1	0.8	134	0.3	40	165	4.7	50	1.4	30%	30%
	Santos #1 UCR2	0.2	31	0.1	9	39	1.1	12	0.3	30%	30%
	Santos #1 UCR3	0.5	82	0.2	25	101	2.9	30	0.9	30%	30%
	Santos #1 UCR4	0.1	23	0.0	7	29	0.8	9	0.2	30%	30%
	Santos #2	282.6	44,928	84.8	13,478	290	8.2	87	2.5	39%	30%
	Santos #3	106.7	16,961	32.0	5,088	110	3.1	33	0.9	19%	30%
	Santos #4	52.4	8,338	15.7	2,501	4,416	125.1	1,325	37.5	40%	30%
	Santos #5	311.9	49,594	62.4	9,919	263	7.4	53	1.5	18%	20%
	Santos #6	60.5	9,613	12.1	1,923	51	1.4	10	0.3	18%	20%
	Santos #7	8.7	1,385	1.7	277	978	27.7	196	5.5	11%	20%
	Santos #8	98.8	15,708	19.8	3,142	55	1.6	11	0.3	23%	20%
	Santos #9	42.6	6,767	8.5	1,353	31	0.9	6	0.2	20%	20%
High (P10 probabilistic estimate)											
	CAM 01	644.6	102,479	128.9	20,496	362	10.2	72	2.0	31%	20%
	JEQ #1	15.3	2,432	15.3	2,432	2,147	60.8	2,147	60.8	29%	100%
	JEQ #2	12.4	1,968	12.4	1,968	1,390	39.4	1,390	39.4	24%	100%
	Santos #1 UCR1	2.6	414	0.8	124	511	14.5	153	4.3	30%	30%
	Santos #1 UCR2	0.5	85	0.2	26	105	3.0	32	0.9	30%	30%
	Santos #1 UCR3	1.5	240	0.5	72	297	8.4	89	2.5	30%	30%
	Santos #1 UCR4	0.4	58	0.1	17	72	2.0	22	0.6	30%	30%
	Santos #2	795.6	126,486	238.7	37,946	818	23.1	245	6.9	39%	30%
	Santos #3	260.7	41,445	78.2	12,434	268	7.6	80	2.3	19%	30%
	Santos #4	116.0	18,444	34.8	5,533	9,769	276.7	2,931	83.0	40%	30%
	Santos #5	1,037.6	164,966	207.5	32,993	874	24.7	175	4.9	18%	20%
	Santos #6	124.9	19,859	25.0	3,972	105	3.0	21	0.6	18%	20%
	Santos #7	19.1	3,041	3.8	608	2,148	60.8	430	12.2	11%	20%
	Santos #8	220.2	35,009	44.0	7,002	124	3.5	25	0.7	23%	20%
	Santos #9	95.1	15,119	19.0	3,024	69	2.0	14	0.4	20%	20%

Prospective Hydrocarbon Resources Statement as of December 31, 2009
Properties offshore Brazil
Gross and Net to Queiroz Galvão Exploração e Produção's Interest

Esti mate	Prospect	Oil / Condensate				Natural Gas				Geologic Chance of Success	QGEP Partici pation
		Gross (100%) Field Volumes		Net to QGEP's Interest Volumes		Gross (100%) Field Volumes		Net to QGEP's Interest Volumes			
		(MMBbl)	(Mm^3)	(MMBbl)	(Mm^3)	(Bcf)	(Bcm)	(Bcf)	(Bcm)	%	%
Mean values											
	CAM 01	353.2	56156	70.6	11231	198	5.6	40	1.1	31%	20%
	JEQ #1	8.5	1351	8.5	1351	1193	33.8	1193	33.8	29%	100%
	JEQ #2	6.9	1091	6.9	1091	770	21.8	770	21.8	24%	100%
	Santos #1 UCR1	1.2	185	0.3	55	228	6.5	69	1.9	30%	30%
	Santos #1 UCR2	0.3	40	0.1	12	50	1.4	15	0.4	30%	30%
	Santos #1 UCR3	0.7	110	0.2	33	137	3.9	41	1.2	30%	30%
	Santos #1 UCR4	0.2	29	0.1	9	36	1.0	11	0.3	30%	30%
	Santos #2	376.6	59877	113.0	17963	387	11.0	116	3.3	39%	30%
	Santos #3	132.2	21010	39.6	6303	136	3.8	41	1.2	19%	30%
	Santos #4	61.5	9784	18.5	2935	5182	146.8	1555	44.0	40%	30%
	Santos #5	455.1	72346	91.0	14469	383	10.9	77	2.2	18%	20%
	Santos #6	70.1	11151	14.0	2230	59	1.7	12	0.3	18%	20%
	Santos #7	10.3	1646	2.1	329	1162	32.9	232	6.6	11%	20%
	Santos #8	116.7	18558	23.3	3712	66	1.9	13	0.4	23%	20%
	Santos #9	50.2	7983	10.0	1597	37	1.0	7	0.2	20%	20%

A detailed description of the volume estimation for each field and prospect classified as Contingent and Prospective Resources is presented in the Appendix I.

Future capital costs were derived from development program forecasts prepared by QGEP for the fields. Recent historical operating expense data were utilized as the basis for operating cost projections. GCA has found that QGEP has projected sufficient capital investments and operating expenses to economically produce the projected volumes. Cashflows are included in Appendix II.

It is GCA's opinion that the estimates of total remaining recoverable hydrocarbon liquid and gas volumes at December 31, 2009 are, in the aggregate, reasonable and have been prepared in accordance with the resources definitions in the Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers in March 2007 attached as Appendix III.

This assessment has been conducted within the context of GCA's understanding of QGEP's petroleum property rights as represented by QGEP management. GCA is not in a position to attest to property title, financial interest relationships or encumbrances thereon for any part of the appraised properties or interests.

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas reserve engineering and resource assessment must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way.

Estimates of oil and gas reserves or resources prepared by other parties may differ, perhaps materially, from those contained within this report. The accuracy of any Reserve or Resource estimate is a function of the quality of the available data and of engineering and geological interpretation.

Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, Reserve and Resource estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

For this assignment, GCA served as an independent Reserve and Resource auditor/evaluator. The firm's officers and employees have no direct or indirect interest holdings in the property units evaluated. GCA's remuneration was not in any way contingent on reported reserve or resource estimates.

Finally, please note that GCA reserves the right to approve, in advance, the use and context of the use of any results, statements or opinions expressed in this report.

Such approval shall include, but not be confined to, statements or references in documents of a public or semi-public nature such as loan agreements, prospectuses, reserve statements, press releases etc.

This report has been prepared for QGEP and should not be used for purposes other than those for which it is intended.

Very truly yours,

GAFFNEY, CLINE & ASSOCIATES, INC.

César Guzzetti
Southern Cone Regional Manager

Attachments

Appendices I Technical Discussion

II: Summary Cashflows

III: Petroleum Resources Management System Definitions and Guidelines

APPENDICES

APPENDIX I:

Technical Discussion

TECHNICAL DISCUSSION

QGEP has interest in certain blocks located in the Camamu, the Jequitinhonha, and the Santos basins in the Brazilian South Atlantic margins.

The **Camamu basin** is located in the southern portion of the coast of Bahia State, and extends onto the coastal plain, covering a total area of 16,500 km^2. It is bounded to the north by the Jacuípe and Recôncavo basins across the transfer zones of Itapoã and Barra, respectively. The Itacare High separates the Almada and Camamu basins. A few oil and gas discovery wells have been drilled in the Camamu Basin by Petrobras and others, of which two are onshore (Morro do Barro/gas and Jiribatuba/oil), and another two offshore (1-BAS-64/oil and the 1-BAS-97/gas).

In the Camamu basin, QGEP has interest in the Manati and Camarão Norte fields, and two exploration blocks: BM-CAL-5 and BM-CAL-12. In block BM-CAL-5 two discovery wells have been drilled and are currently under evaluation.

The **Jequitinhonha Basin** is located in the northeast portion of the East Brazilian margin, on the southern Bahian coast opposite the mouth of the Jequitinhonha River. The Olivenca High defines the northern boundary with the Camamu-Almada Basin and the volcanic Royal Charlotte Bank marks the southern boundary with the Cumuraxitiba Basin. It occupies an area of 10,100 km^2, of which 9,500 km^2 is offshore (7,000 km^2 to a water depth of 1,000m and 2,500 km^2 between 1,000 and 2,000m). The drilling of 33 exploration wells in the basin, by Petrobras and others has resulted in one discovery in the area of the well 1-BAS-37.

In the Jequitinhonha Basin QGEP has interest in block BM-J-2, where two prospects have been identified.

The **Santos Basin** is one of the largest sedimentary basins in Brazil. It is located on the southeast portion of the Brazilian continental margin, offshore from Rio de Janeiro, Sao Paulo, Parana and Santa Catarina States. The southern boundary with Pelotas Basin is Florianopolis High and the northern boundary with the Campos Basin is Cabo Frio High. The basin covers a total area of 352,260 km^2 and has up to 3,000m isobath, and the most extensive of Brazil's coastal basins. Exploration activities in the Santos basin commenced in the 1960s. There have been a few discoveries including the Merluza gas field, and the Caravela and Coral oil fields until the last few years, when a sequence of important discoveries were made: this discovery cycle started with Lagosta, Mexilhão, Tambaú and Uruguá and is ongoing with giant pre-salt discoveries of Tupi, Carioca, Caramba, Parati, Guará, Bem-Te-Vi, Júpiter and Lara. Today the Santos basin is considered the most important of the offshore Brazil.

QGEP has interest in four Santos Basin Blocks: BM-S-12, BM-S-75, BM-S-76, and BM-S-77. 1-SCS13 well was drilled in block BM-S-12 in 2004. The well's main target was the pre-salt microbiolite reservoirs with secondary targets in the Albian and Oligocene. The well was abandoned because of a gas kick and subsequent mechanical problems while drilling the top of the Late Albian sandstones. The primary pre-salt target was never reached.

Regional Petroleum Geology

The formation of the South Atlantic basin commenced during the Jurassic Period when rifting began in the Atlantic Ocean. Alluvial red beds and shales filled the rift basin comprising the source rock for this petroleum system. Concurrently to the sag period en evaporate sequence was deposited during the Aptian geologic time. The depositional distribution of the Aptian salt in the South Atlantic area played a key role in trapping hydrocarbons sourced from the syn-rift successions. The Atlantic Ocean opened, and the drift phase started with continental shelf sedimentation of extensive shallow marine carbonates with a restricted fauna, probably controlled by high salinities, and clastic fan deltas. Further offshore, marls and shales were deposited on the continental slope. Sea levels continued to rise and a series of sands and shales were deposited. In the Cenomanian an anoxic event occurred and produced black shales with high total organic matter levels. These black shales are better developed on the African margin than they are in the Brazilian margin. During this transgressive open marine sequence, Cenomanian turbiditic sandstones were deposited along most of the Brazilian margin, which locally can be high quality reservoirs (common in the Campos Basin). From Campanian to Santonian times oxic conditions were widespread. The onset of the progradation varies along the margin from the Turonian times in the Santos Basin to Eocene age in the Sergipe-Alagoas Basin, north of the Camamu basin. Large turbidite fans from Albian to Early Miocene age, poured into the southern basins during low sea level stands and periods of tectonic movement.

Source and Migration

In general, mature source rocks are present along most of the Brazilian Atlantic margin and began generating hydrocarbons in Late Cretaceous-Tertiary times. The pre-salt lacustrine shales are considered to be the most important source is the South Atlantic Brazilian basins. Additional source rocks are found in open marine shales of mid-late Cretaceous age.

Salt movement, or halokinesis, played a particularly important role in determining directions of migration. Thick Aptian evaporates create a perfect seal for pre-salt generated hydrocarbons, but can also cause problems in their migration from the pre-salt source rocks into the post-salt reservoirs. Due to halokinesis openings and thinning occurred along the regional salt seal that allowed migration to the post-salt reservoirs, either directly or via welds and faults which are common in thin salt beds due to dissolution and mechanical salt withdrawal. Growth faults also developed above the salt due to gravity sliding and oil can migrated up these faults into post-salt reservoirs.

In addition to creating migration pathways, salt movement created localized depositional changes that enhanced reservoir quality on and around the growing salt structures, including the distribution of turbidites, and in other locations provided structural reliefs conducive to the entrapment of hydrocarbons.

Reservoirs

In the Brazilian margin hydrocarbons are found in a variety of reservoirs from the pre-salt fractured basement to Miocene turbidites, in a succession of sand rich clastic sediments, carbonates, and shales. The thick shales deposits in between the clastics and the carbonates create good top seal to those reservoirs.

Pre-salt reservoirs are comprised by a variety of deposits depending on the rift phase and the depositional environment. The initial depocenters were filled with coarse continental clastics that occasionally contain interbedded volcanic. Further pull apart created horsts and grabens, generally parallel to the coastline. Erosion of the horsts provided thick sequences of fluvio-clastic sediments that were deposited in the adjoining grabens. Locally source rocks have been developed, as well as reservoirs of secondary regional importance. In contrast, carbonates were deposited around lacustrine shales that can provide good reservoirs.

Following the deposition of the Aptian evaporites, continuing deepening of the South Atlantic resulted in the deposition of the Albian carbonates, followed by shale and sandstone sequences. This trend continued in the late Cretaceous and Tertiary, while salt movement resulted to a complex structural configuration of the sediments. In the Oligocene withdrawal of the sea led to the development of erosional channels which subsequently filled with marine channel sands and turbidites related to the late drift phase.

Contingent and Prospective Resources Estimate

Petrobras has drilled three wells in two of the blocks that QGEP has interest in: two of them are located in the BM-CAL-5 block one in the Copaíba and the other in the Jequitibá accumulation in the Camamu Basin. The third well was drilled in Block BM-S-12 block in the Santos Basin. All three of these wells demonstrate the existence of hydrocarbons in the zones they penetrated, establishing a discovery and a basis for development consideration. As the operators have not established specific plans to develop these discoveries the estimated recoverable volumes are classified by GCA as Contingent Resources.

In addition to these, QGEP has identified one more prospect in the Camamu Basin, the Cam-01 in the BM-CAL-12 Block, and 9 more opportunities in the Santos Basin.

Available data

QGEP provided GCA with data and information regarding each prospect. This included:

- Several seismic sections of 3D seismic data with QGEP's stratigraphic and structural interpretation
- Structural depth maps on key horizons related with each play
- Isopach maps for several of the plays
- Composite well logs used and derived petrophysical parameters
- Studies and analysis regarding source maturation and geologic timing relevant to the plays
- Additional reports and supporting analyses used in the estimation of additional parameters such as Formation Volume Factor, Recovery Factors and Gas Oil Ratios, where available.

Data Review

GCA reviewed the provided data and QGEP's interpretations and found that they were in general reasonable. Seismic data were fair to good in most cases, enough to support given interpretations. Derived structural and isopach maps seem to tie well tops where available. The quality of the seismic data in most areas offers high confidence in the mapping. However uncertainties still exist for the accuracy of the structural interpretations since well data are not available to accurately calibrate the seismic data.

Similarly, porosity and water saturation parameters derived by QGEP from the logs were easily confirmed in the provided data. GCA also validated the estimate of Formation Volume Factors if data were available. If data were not available for the estimate of Formation Volume Factors, GCA accepted QGEP's estimates, since they appeared reasonable.

Resource Estimate Methodology

The estimation of the Recoverable Volumes was based on the volumetric estimate method:

$$EUR = A*H*\Phi*Sh*(1/FVF)*RF$$

Where:

EUR Estimated Ultimate Recovery of hydrocarbons

A Area of accumulation derived from the structure maps down to defined depth, varying by case based on lowest known hydrocarbons, hydrocarbon water contact, or structural spill point

H Average Net Thickness derived as an average value from net pay maps. If net pay maps where not available this value was derived from the structure maps and the net to gross value that resulted from well logs that penetrated the corresponding reservoir.

Φ Average Porosity; derived as an average value from available log information

Sw Average hydrocarbon saturation derived as an average value from available log information

FVF Formation volume factor calculated based on reservoir depth and expected hydrocarbon properties

RF Recovery Factor estimated based on reservoir characteristics

The EURs for oil and gas were calculated probabilistically using Monte Carlo simulations. The input parameters were determined for low, most likely, and high cases and were input as the P90, P50, and P10 percentiles respectively in triangular distributions. In few exceptions, the area low and high were input in the triangular distribution as minimum and maximum, mainly in accumulations where the areal extend was limited to the block limits and not to the limits of the mapped geological features (noted if applicable on the input parameter table of the relevant prospects).

Within the Monte Carlo simulations some parameters were assumed to be dependent in order to eliminate unrealistic scenarios as follows:

Independent Variable	Dependant Variable	Correlation Coefficient
H	*Φ*	0.5
H	*RF*	0.5
Φ	*Sh*	0.7

Geologic Chance of Success

In addition to the volumetric estimate of QGEP's prospective resources in the Brazilian margin, QGEP also requested from GCA to provide an estimate of the Geological Chance of Success (GCOS) for each of the prospects.

The assignment of a GCOS to a prospect is routinely undertaken within the industry as one of the steps in assessing whether or not a prospect is worthy of drilling. While there are systematic procedures for estimating GCOS, the process nonetheless essentially remains one of judgment. The GCOS estimate is an aggregate of individual probabilities that contribute to geologic success such as:

Trap and Seal

Reservoir presence and quality

Source and Migration, and

Geologic Timing

In general it can be said that because of the presence of numerous other oil and gas fields near to QGEP's exploratory blocks, and some wells where the potential reservoir formations can be seen to exist suggest that the risks associated with hydrocarbon generation and hydrocarbon migration and with the presence of reservoir are all relatively small. Nevertheless, because of the complex structural and stratigraphic configuration of many of the identified targets as well as the role of the salt presence and lack of as a key component in the effectiveness of the migration pathways careful consideration needs to be taken in estimating the GCOS for each prospect.

Contingent Resources

Camamu Basin - Block BM-CAL-5

Copaíba Contingent Resources

The Copaíba accumulation was drilled by the 1-BRSA-637D-BAS well. The target is a lacustrine lower cretaceous turbidite channel, stratigraphic in nature. The well tested 1000-2000 bbl/day. Further evaluation is pending before proceeding in additional drilling. The evaluated low and high areal extensions are limited to the immediate vicinity of the well penetration. Seismic amplitude mapping indicates this channel feature may extend to the North. However, additional data are necessary to further evaluate any additional potential.

Copaíba Field - Original Oil in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	So (%)	Bo (v/v)
Low	4.6	17	18	70	1.115
Most Likely	7.7	19	21	80	
High	11.5	22	24	90	

Jequitibá Contingent Resources

The Jequitibá accumulation was drilled by the 1-BAS-144 well and found the top of the Jurassic (pre-rift section) Sergi sandstone formation gas productive in it's A, B, C, D and top of E intervals. A Gas/Water Contact (GWC) was identified a few meters below the top of the "E" sandstone of the Sergi. The seismic data show the reservoir compartmentalized into three main fault blocks. The well penetrated the structurally highest fault block. Average porosities and hydrocarbon saturations were derived from the well log. Areal extension for the low case includes only the penetrated fault block, while the high case includes all three blocks down to the GWC.

Jequitibá Field - Original Gas in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	Sg (%)	1/Bg (v/v)
Low	1.2*	30	10	70	290
Most Likely	4.5	45	13	75	295
High	9.0**	60	18	80	300

*Minimum input in triangular distribution
**Maximum input in triangular distribution

Santos Basin - Block BM-S-12

In this block, the well 1–SCS-13 was drilled in 2004. The main target of the well was the Aptian pre-salt microbiolite sequence. Secondary targets of the well included the Albian sandstones and carbonates and the shallow Oligocene sandstones. The well encountered 3 meters of pay at a depth of about 2,600 m in the Oligocene sandstones and had gas shows in the mud log. This reservoir is the equivalent of the reservoirs producing gas in the adjacent fields of Tiro, Sidon, and Piracuca.

The well was further drilled down to more than 5,000 m where it encountered a gas kick. Additional mechanical problems resulted in the abandonment of the well without reaching the main target.

Based on the logs seen from this well, GCA considers that the 1-SCS-13 well discovered the Oligocene gas reservoir, which can be considered for development by the operator. Therefore, volumes associated with this accumulation can be considered as contingent resources.

Santos 01 – Discovered Resources areal extents

Vertically, the well found only 3 meters of a gas sand. Below those 3 meters, there are about 3 meters of shale on top of a very thin, 1 meter, sand which appears wet. Thus, a GWC was inferred to exist somewhere in between the two sands. No additional pressures or other data exist to confirm a GWC at that level. However, for the purpose of assigning Contingent Resources, GCA considered a depth of -2,625 m sub-sea as highest known water, and the limit of the reservoir.

As far as the areal extents are concerned, GCA considered a low estimation of 3 km^2 represented by strong seismic amplitudes seen around the well. The high estimate area was based on the structure map down to the HKW level of -2625 in the vicinity of the well, as mapped by Petrobras.

Santos 01 Discovered Resources- Original Gas in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	Sg (%)	1/Bg (v/v)
Low	3	3	25	55	190
Most Likely	5	4	27	60	210
High	12	6	30	65	220

Petrobras and QGEP seismic amplitude studies show that even brighter amplitudes can be mapped regionally at the same interval. GCA considered this interpretation but because of the thin sands encountered in the well and the discontinuities seen on the amplitude map it concluded that any areas away from the ones associated with the 1-SCS-13 well can still be considered as Prospective Resources since there is no strong evidence of a GWC in the well. These resources will be discussed later in this report.

Prospective resources

Camamu basin - Block BM-CAL-12 - CAM-01 Prospect

The target reservoirs in this prospect are marine upper cretaceous turbidites. This reservoir has been seen in the wells close to the block. The Bas-126 drilled north of the block has over 250 meters of good quality reservoir, and the Bas-102 well drilled south of the block has over 100 meters of good quality reservoir. GCA found the provided Petrobras structure map to be reasonable and verified the input parameters used by QGEP in the volumetric estimate for this prospect as follows:

CAM-01 Prospect - Original Oil in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	So (%)	Bo (v/v)
Low	12*	20	16	65	1.100
Most Likely	30	40	21	70	1.200
High	80**	60	25	75	1.300

*Minimum input in triangular distribution
**Maximum input in triangular distribution

According the geochemical studies in the area oil is expected to be the predominant hydrocarbon if present. The GCA estimated Geologic Chance of Success for this prospect is 31%:

Jequitinhonha Basin

Block BM-J-2: JEQ-01 and JEQ-02 prospects

The target reservoirs in this pre-salt structural play are Albian to Tertiary fractured siliciclastics and carbonates. The trap is a pre-salt structural high that is expected to be similar to producing structures found in the Campos Basin.

In this configuration, two prospects have been identified in close proximity to each other. The seismic data at this depth is somewhat poor and even though the structural high can be seen at the base of salt, the resolution of the data below the salt offers low confidence in the mapping of the structure. QGEP used the mapping of the base of the salt to identify the best expression for each prospect. Based on regional geochemical studies the expected hydrocarbon in this area and reservoir is gas.

GCA found QGEP's analysis reasonable, verified the input parameters used for the volumetric estimate and assessed the Geologic Chance of Success for each of the prospects obtaining 29% for JEQ-01 and 24% for JEQ-02.

JEQ-01 Prospect - Original Gas in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	Sg (%)	1/Bg (v/v)
Low	12	60	10	60	250
Most Likely	25	75	12	70	270
High	41	90	15	80	285

JEQ-02 Prospect - Original Gas in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	Sg (%)	1/Bg (v/v)
Low	7	60	10	60	285
Most Likely	15	75	12	70	297
High	24	90	15	80	310

Santos Basin

BM-S-12 - Santos-01 prospective resources

As discussed earlier, GCA found one part of this prospect to be discovered by the 1-SCS-13 well. Based on the Petrobras/QGEP amplitude map, there are indications that the reservoir encountered by 1-SCS-13 well may be part of a regionally extensive channel system which is seen in this map as bright amplitudes.

These amplitudes however are not continuous and distinct lateral breaks can be identified, as it has been mapped by Petrobras/QGEP. Based on the Petrobras/QGEP map, GCA evaluated this play as 4 prospects, additional to the contingent resources assigned to the 1-SCS-13 well area.

Original Gas in Place Input parameters

Santos-01-UCR-01 Prospect

	Area (km^2)	Net H (m)	Phi (%)	Sg (%)	1/Bg (v/v)
Low	7	3	25	55	190
Most Likely	23	6	27	60	210
High	57	14	30	65	220

Santos-01-UCR-02 Prospect

	Area (km^2)	Net H (m)	Phi (%)	Sg (%)	1/Bg (v/v)
Low	3	3	25	55	190
Most Likely	7	6	27	60	210
High	11	14	30	65	220

Santos-01-UCR-03 Prospect

	Area (km^2)	Net H (m)	Phi (%)	Sg (%)	1/Bg (v/v)
Low	7	3	25	55	190
Most Likely	14	6	27	60	210
High	33*	14	30	65	220

* Limited inside the block; additional 25 km^2 for the high case are outside the block

Santos-01-UCR-04 Prospect

	Area (km^2)	Net H (m)	Phi (%)	Sg (%)	1/Bg (v/v)
Low	3	3	25	55	190
Most Likely	5	6	27	60	210
High	7	14	30	65	220

GCA finds all of these prospects to have a similar Geologic Chance of Success of 30%

BM-S-12 - Santos-02

The reservoir for this prospect pertains to the Late Albian sandstones, with regional distribution in the Brazilian margin. This reservoir was penetrated by the 1-SCS-13 well before the well failed. At 5,032 m MD the mudloggers observed oil in the shale shakers. Soon after, problems started developing at the well location, including a gas kick. The drillers changed the water base mud to oil base mud in one of the attempts to control the well. Therefore, all samples below that interval are contaminated and inconclusive. Based on the geochemical studies in the area, oil is more likely to be present in these reservoirs than gas.

Post-well, Petrobras carried-out a study on the Santos-02 prospect, including AVO analysis in an attempt to identify Direct Hydrocarbon Indicators (DHI). AVO was not responsive in this reservoir. GCA analyzed all the inputs and found the Petrobras/QGEP low case map to be optimistic. It is GCA's estimate that Petrobras/QGEP low case map would better represent the most likely case. For the low case, GCA believes that the area should be restricted at East of the fault to the West of the 1-SCS-13 well. For the remaining parameters GCA agreed with QGEP.

Santos-02 Prospect - Original Oil in Place Input parameters, limited to Block outline

	Area (km^2)	Net H (m)	Phi (%)	So (%)	Bo (v/v)
Low	30*	12	10	50	1.500
Most Likely	153**	20	12	60	1.650
High	346***	44	14	70	2.100

*Minimum input in triangular distribution; P90 projected at 91 km^2
**From Petrobras P90 map; area limited at Block outline
***Maximum input in triangular distribution limited at Block perimeter; maximum area on Petrobras interpretation extends to 655 km^2

GCA estimated for this prospect a Geologic Chance of Success of 39%.

BM-S-12 - Santos-03

The reservoir rocks in this prospect are the Albian saccaroidal dolomites. In general, the trap configuration is stratigraphic and the presence and ability for these reservoirs to be charged includes some uncertainty. Regardless, in this block the seismic data are good quality and reveal an event that can be easily tracked and mapped. GCA has found QGEP analysis and interpretation reasonable.

Santos-03 Prospect - Original Oil in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	So (%)	Bo (v/v)
Low	40	15	7	55	1.400
Most Likely	60	25	9	60	1.600
High	125	35	12	65	1.800

GCA estimated for this prospect a Geologic Chance of Success of 19%.

BM-S-12 - Santos-04

This prospect is targeting pre-salt Aptian Microbiolitic reservoirs.

The block is located at the edge of the pre-salt ring fence, however according to QGEP analysis, source pods possibly exist in the area of the Block. In that case major faults in the pre-salt sequence can facilitate migration. Regional geochemical studies suggest the Aptian microbiolites at this depth of 6,400 meters are more likely to contain gas than oil. Structurally there are two parallel highs in the bottom of the salt, in which the microbiolite reservoir may be better developed.

GCA verified the input parameters used by QGEP, found them reasonable and proceeded in the volumetric estimation with the following input parameters:

Santos-04 Prospect - Original Gas in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	Sg (%)	1/Bg (v/v)
Low	56	30	9	60	400
Most Likely	110	50	10	70	430
High	189	70	12	80	500

GCA estimated for this prospect a Geologic Chance of Success of 40%.

BM-S-75, BM-S-76 and BM-S-77 - Santos-05, Santos-06, and Santos-07

These three prospects are all stratigraphic plays targeting late Cretaceous sandstone reservoirs. These sands are regionally distributed, and even though the closest well that encountered this type of sands is the Chev-1 well, about 50km to the NE, prospects are possibly located in a regional trend of upper cretaceous sandstones. Fields like Mexilhao and Merluza produced from similar stratigraphic traps and reservoirs. Geochemical regional studies suggest that the predominant hydrocarbon is oil for prospects Santos-05 and Santos-06 and gas for the

Santos-07 prospect. All three of the accumulations related to these prospects have been mapped to extend beyond the block limits, in the probabilistic distributions. However measured areas have been limited to the Block limits. GCOS estimates vary for each prospect based on its setting in the basin.

Santos-05 Prospect - Original Oil in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	So (%)	Bo (v/v)
Low	27	20	9	60	1.500
Most Likely	80	30	11	65	1.600
High	179	75	15	75	1.700

Santos-06 Prospect - Original Oil in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	So (%)	Bo (v/v)
Low	7*	25	10	60	1.500
Most Likely	20	30	11	65	1.600
High	42**	45	13	75	1.700

*Minimum input in triangular distribution; P90 projected at 14 km^2

** Maximum input in triangular distribution limited to Block outline; potential accumulation may extend beyond Block outline (15 km^2 more for the high case area, based on QGEP mapping)

GCA estimated for prospects Santos-05 and Santos-06 similar Geologic Chance of Success of 18%.

Santos-07 Prospect - Original Gas in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	Sg (%)	1/Bg (v/v)
Low	15*	30	10	65	280
Most Likely	25	35	13	70	290
High	60**	75	16	75	300

*Minimum input in triangular distribution; P90 projected at 22 km^2

** Maximum input in triangular distribution limited to Block outline

GCA estimated for this prospect a Geologic Chance of Success of 11%.

BM-S-76 and BM-S-77 - Santos-08

This prospect targets Oligocene sandstones in a stratigraphic play. These sandstones have been found oil productive in the Tiro and Sidon fields no more than 20 km^2 from the blocks. Although the accumulation extends well beyond the block limits, the volumetric estimated area has been limited to the block outlines.

GCA found QGEP's input parameters for this prospect reasonable:

Santos-08 Prospect - Original Oil in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	So (%)	Bo (v/v)
Low	10*	10	17	60	1.100
Most Likely	30	15	20	70	1.200
High	56*	22	25	80	1.300

*Minimum input in triangular distribution; P90 projected at 20 km^2
** Maximum input in triangular distribution limited at Blocks outline; additional potential may exist outside Blocks in which QGEP participates

GCA estimated for this prospect a Geologic Chance of Success of 23%.

BM-S-77 - Santos-09

This prospect was mapped as a small elongated three way closure, trapped to the north by an east-west trending fault. In this very small elongated geological feature, mapping can be very sensitive to small velocity variations. Trap depends highly on the sealing fault to the north. The target reservoirs are the Santonian sandstones. The area of the accumulation extends beyond the block to the west. Based on QGEP analysis the input to the volumetric estimate is as follows:

Santos-09 Prospect - Original Oil in Place Input parameters

	Area (km^2)	Net H (m)	Phi (%)	So (%)	Bo (v/v)
Low	4*	20	20	60	1.100
Most Likely	7	30	22	65	1.200
High	11**	45	25	75	1.300

*Minimum input in triangular distribution; P90 projected at 5.5 km^2
**Maximum input in triangular distribution limited to Block outline; potential accumulation may extend beyond Block outline (6 km^2 more for the high case area, based on QGEP mapping)

GCA estimated for this prospect a Geologic Chance of Success of 20%.

APPENDIX II:

Summary Cashflows
Manati Field
As of December 31, 2009

Queiroz Galvão Exploração e Produção Net Interest Reserve Cashflows
as of December 31, 2009
Manati Field

Proved Developed Reserves

	Condensate	Sales Gas	Condensate Price	Sales Gas Price	Gross Income	Royalty	PIS/PASEP/COFINS	Special Participation +P&D Tax	Operating Expenses	Capital Expenditures	Abandonment Cost	Income Tax Social Contr.	AIT Net Cashflow	10% Discounted Cashflow
	Mbbl	Bscf	US$/Bbl	US$/Mscf	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2010	103	34.8	88.94	7.74	278	16	59		18	9		28	148	141
2011	103	34.8	93.76	7.89	284	17	60		18	2		29	159	138
2012	103	34.9	96.02	8.05	291	17	62	4	18			29	161	127
2013	100	33.8	95.21	8.21	287	17	61	10	19			27	153	110
2014	83	28.0	94.59	8.38	242	14	51	7	19			23	128	83
2015	65	21.9	96.33	8.54	194	11	41	3	19			18	101	60
2016	38	12.9	98.25	8.71	116	7	25		19			10	56	30
2017	17	5.7	100.22	8.89	52	3	11		19			3	16	8
2018											59		-59	-26
2019														
2020														
2021														
2022														
2023														
Total	611	206.8			1,745	103	371	23	148	11	59	166	863	670

Total Proved Reserves

	Condensate	Sales Gas	Condensate Price	Sales Gas Price	Gross Income	Royalty	PIS/PASEP/COFINS	Special Participation +P&D Tax	Operating Expenses	Capital Expenditures	Abandonment Cost	Income Tax Social Contr.	AIT Net Cashflow	10% Discounted Cashflow
	Mbbl	Bscf	US$/Bbl	US$/Mscf	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2010	103	34.8	88.94	7.74	278	16	59		18	9		28	148	141
2011	103	34.8	93.76	7.89	284	17	60		18	2		29	159	137
2012	103	34.8	96.02	8.05	290	17	62	4	18			29	160	126
2013	100	33.8	95.21	8.21	287	17	61	10	19			27	153	109
2014	83	28.0	94.59	8.38	242	14	51	7	19			23	128	83
2015	69	23.2	96.33	8.54	205	12	44	3	32			17	97	57
2016	69	23.2	98.25	8.71	209	12	44	3	33			18	99	53
2017	69	23.2	100.22	8.89	213	13	45	3	33			18	101	49
2018	53	17.8	102.22	9.07	167	10	36		34			13	75	33
2019	41	13.7	104.27	9.25	131	8	28		34			9	52	21
2020	31	10.6	106.35	9.43	103	6	22		34			6	34	13
2021	24	8.1	108.48	9.62	81	5	17		35			4	20	7
2022											64		-64	-19
2023														
Total	845	286.1			2,491	147	529	31	327	11	64	220	1,162	812

GCA Engineer:	RW	Approved:	DKM

Queiroz Galvão Exploração e Produção Net Interest Reserve Cashflows
as of December 31, 2009
Manati Field

Proved plus Probable Reserves

	Condensate	Sales Gas	Condensate Price	Sales Gas Price	Gross Income	Royalty	PIS/PASEP/COFINS	Special Participation +P&D Tax	Operating Expenses	Capital Expenditures	Abandonment Cost	Income Tax Social Contr.	AIT Net Cashflow	10% Discounted Cashflow
	Mbbl	Bscf	US$/Bbl	US$/Mscf	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2010	103	34.8	88.94	7.74	278	16	59		18	9		28	148	141
2011	103	34.8	93.76	7.89	284	17	60		18	2		29	159	137
2012	103	34.8	96.02	8.05	290	17	62	4	18			29	160	126
2013	103	34.8	95.21	8.21	296	17	63	10	31			26	148	106
2014	103	34.8	94.59	8.38	301	18	64	10	32			27	150	98
2015	103	34.8	96.33	8.54	307	18	65	10	33			27	153	91
2016	103	34.8	98.25	8.71	313	19	67	11	33			28	156	84
2017	103	34.8	100.22	8.89	320	19	68	11	34			29	159	78
2018	83	28.2	102.22	9.07	264	16	56	7	34			23	128	57
2019	67	22.8	104.27	9.25	218	13	46	3	35			18	102	41
2020	54	18.4	106.35	9.43	180	11	38		35			15	81	30
2021	44	14.9	108.48	9.62	148	9	32		35			11	62	21
2022	36	12.1	110.65	9.81	122	7	26		36			8	45	14
2023	29	9.8	112.86	10.01	101	6	21		37			6	31	9
2024	23	7.9	115.12	10.21	83	5	18		37			4	20	5
2025											68		-68	-15
Total	1,159	392.5			3,506	207	745	66	466	11	68	307	1,636	1,022

Proved plus Probable plus Possible Reserves

	Condensate	Sales Gas	Condensate Price	Sales Gas Price	Gross Income	Royalty	PIS/PASEP/COFINS	Special Participation +P&D Tax	Operating Expenses	Capital Expenditures	Abandonment Cost	Income Tax Social Contr.	AIT Net Cashflow	10% Discounted Cashflow
	Mbbl	Bscf	US$/Bbl	US$/Mscf	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2010	103	34.8	88.94	7.74	278	16	59		18	9		28	148	141
2011	103	34.8	93.76	7.89	284	17	60		18	24		28	136	118
2012	103	34.8	96.02	8.05	290	17	62	4	18			28	161	127
2013	103	34.8	95.21	8.21	296	17	63	10	31			26	148	106
2014	103	34.8	94.59	8.38	301	18	64	10	32			27	151	98
2015	103	34.8	96.33	8.54	307	18	65	10	33			27	154	91
2016	103	34.8	98.25	8.71	313	19	67	11	33			28	157	84
2017	103	34.8	100.22	8.89	320	19	68	11	34			28	160	78
2018	103	34.8	102.22	9.07	326	19	69	11	35			29	163	73
2019	86	29.0	104.27	9.25	277	16	59	7	35			24	135	55
2020	71	24.1	106.35	9.43	235	14	50	4	35			20	112	41
2021	59	20.0	108.48	9.62	199	12	42	2	36			16	91	31
2022	49	16.7	110.65	9.81	169	10	36		36			13	74	22
2023	41	13.9	112.86	10.01	143	8	30		37			10	57	16
2024	34	11.5	115.12	10.21	122	7	26		37			8	44	11
2025	28	9.6	117.42	10.41	103	6	22		38			6	32	7
2026	24	8.0	119.77	10.62	88	5	19		39			4	21	4
2027											80		-80	-15
Total	1,317	445.9			4,052	239	861	80	545	34	80	350	1,863	1,088

GCA Engineer:	RW	Approved:	DKM

APPENDIX III:

Resource and Reserve Definitions

Production Resource Management System (PRMS) SPE-WPC-AAPG-SPEE March 2007

Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers

Petroleum Resources Management System

Definitions and Guidelines (1)

March 2007

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definition of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in Resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE PRMS document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.,

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that SPE PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE PRMS Definitions and Guidelines can be viewed at:
www.spe.org/specma/binary/files/6859916Petroleum_Resources_Management_System_2007.pdf

1 These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

On Production

The development project is currently producing and selling petroleum to market.

The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

Approved for Development

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Justified for Development

Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.

In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

Proved Reserves

<u>Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations</u>.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

(1) the area delineated by drilling and defined by fluid contacts, if any, and

(2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see ‘‘2001 Supplemental Guidelines,’’ Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

<u>Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.</u>

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

<u>Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves</u>

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain**.** Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Developed Reserves

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate but which have not yet started producing,
(2) wells which were shut-in for market conditions or pipeline connections, or
(3) wells not capable of production for mechanical reasons.

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments:

(1) from new wells on undrilled acreage in known accumulations,
(2) from deepening existing wells to a different (but known) reservoir,
(3) from infill wells that will increase recovery, or
(4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to
    (a) recomplete an existing well or
    (b) install production or transportation facilities for primary or improved recovery projects.

CONTINGENT RESOURCES

Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

Development Pending

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Development Unclarified or on Hold

A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.

PROSPECTIVE RESOURCES

Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

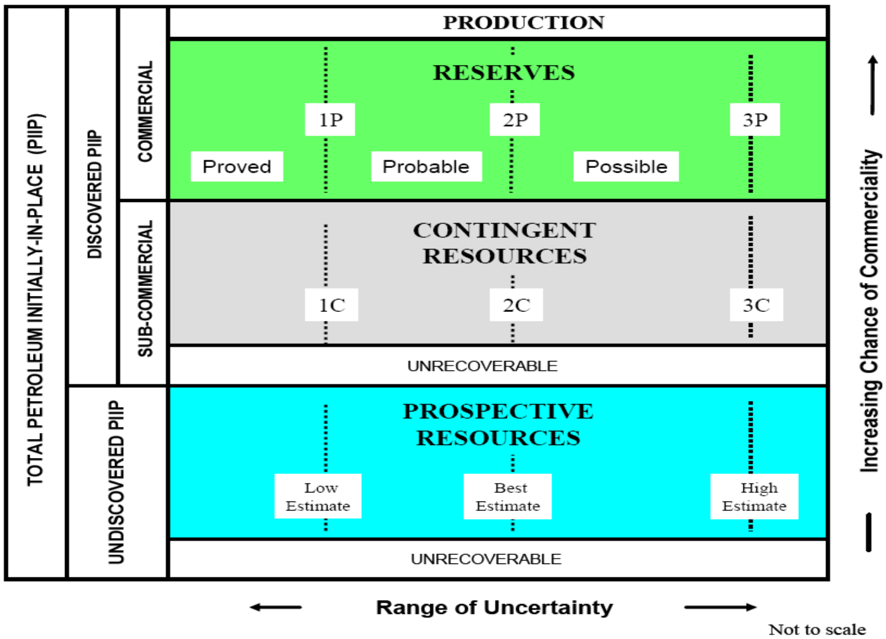
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Play

A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

RESOURCES CLASSIFICATION



PROJECT MATURITY